EnerMark
INCOME FUND

1999
annual report

corporate Profile

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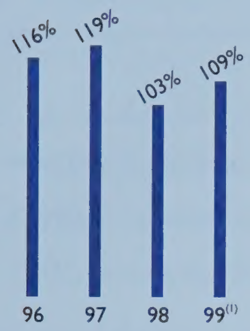
THE ENERMARK INCOME FUND ("EnerMark" or the "Fund") was created in April of 1996 pursuant to the reorganization of Mark Resources Inc. into a Royalty Trust Fund. EnerMark is an investment trust designed to provide regular cash distributions to investors seeking exposure to the oil and gas industry. It offers the benefits of owning producing oil and natural gas properties without the exploration risks associated with owning oil and natural gas common shares. The Fund is the newest member of The Enerplus Group, an employee-owned advisory and management group established in 1985 to provide a wide range of specialized energy-related investment services for investors.

With oil and natural gas common share investments, earnings are retained primarily for reinvestment. With EnerMark however, all net cash flow generated from the properties is paid to the Fund's Unitholders after any deductions for debt servicing and minimal capital expenditure funding. The Units are eligible for all RRSPs, RRIFs and DPSPs.

EnerMark holds interests in oil and natural gas producing properties in western Canada which produced an average of 20,567 BOE/d in 1999. The Fund is committed to maximizing Unitholders' interests and ensuring long-term, steady cash flow through its strategy of replacing depleted reserves on an ongoing basis. The development and operation of properties in a prudent, cost conscious manner while ensuring the safety of employees, the public and the environment, is also a fundamental strategy of EnerMark.

1999 Highlights

Reserves Replacement



Increased the Fund's established reserves by 9% in 1999, resulting in a total reserves increase of 56% since inception

Established Reserve Life Index

(years)

EnerMark's established reserve life index increased to 15.5 years in 1999

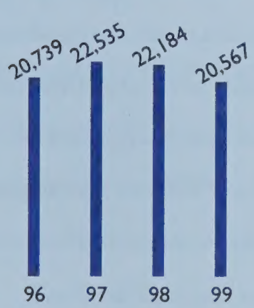
Net Cost of Established Reserve Additions

($/BOE)

The Fund replaced over 230% of its 1999 production volumes at a cost of $4.62/BOE

Daily Production

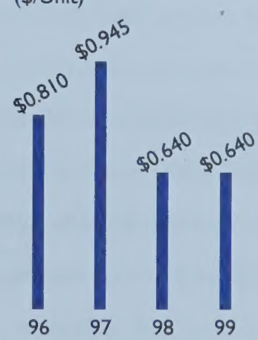
(BOE/d)



Daily production decreased by 7% from 1998 levels

Cash Available for Distribution

($/Unit)



Cash available for distribution remained constant with 1998 levels

(1) Reserve statistics include the acquisition of Hanna Garden properties, effective December 31, 1999 and Western Star Exploration Ltd., effective January 7, 2000.

THROUGH A NUMBER OF SUCCESSFUL acquisitions concluded throughout 1999 and the early part of 2000, EnerMark Income Fund replaced 233% of its daily production and 109% of its established reserves. A total of 10 million barrels of oil equivalent (BOE) were added to the reserve base at a very low net cost of $4.62 per BOE. This is the fourth consecutive year that the Fund has recorded an increase in established reserves, which now are 55% higher than at the inception of EnerMark.

message to Unitholders

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THE 1999 YEAR WAS A CHALLENGING ONE FOR your income fund as a result of the uncertainty generated by the volatility of crude oil prices and the unprecedented lack of investor confidence in the Canadian oil and gas sector in general and the conventional oil and gas income fund sector in particular.

Crude oil prices remained at depressed levels through the first half of 1999. A worldwide reduction in oil production accounted for a significant recovery, whereby in the last six months of the year, prices escalated to levels not experienced since the Gulf War in the early '90's.

EnerMark Income Fund was directly affected by the fluctuations in crude oil prices and the price of the EnerMark Units posted a modest recovery during the year. However, the Units are still lagging the recovery in commodities prices in a significant way as they currently trade at a yield of approximately 20% based on the indicated cash distribution of $0.06 per month, even after allowing for the application of a portion of cash flow generated toward debt reduction to maintain the Fund's strong financial position.

During 1999, the price of properties continued to rise spurred by the increasing presence of American oil and gas companies wishing to enter Canada through the acquisition of an existing company or wanting to expand their Canadian operations. Because of its conservative acquisition criteria, EnerMark encountered difficulties in competing for producing assets and alternately concentrated its efforts on corporate acquisitions. As a result, the Fund was successful in making significant acquisitions including a working interest in the David area of Alberta for $3.7 million, a 20% working interest in the properties of Derrick Energy Corporation at a net cost of $2.9million. In early 2000, the Fund also purchased Western Star Exploration for $28 million and a large interest in a long-life natural gas property at Hanna Garden for consideration of $13 million in cash and 6,050,000 Trust Units of the Fund.

1999 Highlights

- THROUGH A NUMBER OF SUCCESSFUL ACQUISITIONS concluded throughout 1999 and the early part of 2000, EnerMark Income Fund replaced 233% of its daily production and 109% of its established reserves. A total of 10 million barrels of oil equivalent (BOE) were added to the reserve base at a very low net cost of $4.62 per BOE. This is the fourth consecutive year that the Fund has recorded an increase in established reserves, which now are 55% higher than at the inception of EnerMark. During the same period, EnerMark also extended its established reserve life index from 11.9 years at the end of 1996 to 15.5 years at the end of 1999.
- 1999 PRODUCTION AVERAGED 20,567 BOE/DAY, down approximately 1.5% from the targeted production levels of 20,870 BOE/day. This reduction was due primarily to delays in placing new production on stream and the impact of the Fund's property divestment program in the early part of 1999. In addition, most of the larger acquisitions were completed at the end of the year and had a minimal impact on the annual average.
- ENERMARK'S ESTABLISHED RESERVES totaled 116.2 million BOE's at the end of 1999, a 9% increase over the 1998 level and a 35% increase over the level reported at December 31, 1996.
- THE FUND ACCELERATED ITS DEVELOPMENT activities in 1999 and participated in the drilling of 105 gross (19.6 net) development wells with the program achieving a 97% success rate. In addition, EnerMark benefited from its largest farm out program to date. A total of 39 farm out wells were drilled at no cost to EnerMark with a 79% success rate.
- ENERMARK'S COMMITMENT TO THE protection of the environment and the health and safety of all persons and communities was emphasized throughout 1999. The Fund is at the forefront of the industry in its efforts to continually improve its training and enforcement programs such as acquisition due diligence investigations and both internal and third party site inspections at selected facilities.

THROUGH A NUMBER OF SUCCESSFUL acquisitions concluded throughout 1999 and the early part of 2000, EnerMark Income Fund replaced 233% of its daily production and 109% of its established reserves. A total of 10 million barrels of oil equivalent (BOE) were added to the reserve base at a very low net cost of $4.62 per BOE. This is the fourth consecutive year that the Fund has recorded an increase in established reserves, which now are 55% higher than at the inception of EnerMark.

2000 Outlook

TO DATE IN 2000, CRUDE OIL AND natural gas prices have been particularly strong but have raised serious inflationary concerns for the economic development of the industrialized nations. As a result, pressures have been applied, primarily by the U.S. government, to induce OPEC and non-OPEC producers to raise production in an attempt to bring about lower oil prices. Notwithstanding these recent developments, we anticipate the price of WTI crude to average between US $22 and US $25 for 2000. We expect natural gas prices to continue their upward trend in the current year due to increased demand from the United States along with the fact that natural gas reserves in North America continue to decline in spite of the higher prices received for the product. The expansion of the pipeline network, primarily to the U.S. markets, is very encouraging for Canadian producers and will ensure strong prices for Canadian natural gas exports in the future.

EnerMark continues to concentrate its efforts on corporate acquisitions which offer the advantages of less competition, better prices and the opportunity to pay for all or part of the transaction with Trust Units of the Fund. Early in 2000, EnerMark made a take-over bid for 100% of Pursuit Resources Corp. for a total purchase price of $114.5 million, including $15 million in cash and the assumption of approximately $35 million in outstanding bank loans. EnerMark's offer was overwhelmingly accepted by Pursuit shareholders, 96.3% of which tendered their shares on April 3, 2000. Consequently, EnerMark's production, cash flow and reserves have increased on a per Unit basis over year end figures and the transaction is therefore accretive to all Enermark Unitholders.

The outlook is very positive for EnerMark and we are optimistic that cash flow and cash distributions will be rising in 2000. As in 1999, EnerMark will continue to focus the majority of its acquisition and development activities on adding natural gas reserves and production that can be immediately contracted at favourable long-term prices.

In closing, I wish to extend my thanks and appreciation to the employees and directors of EnerMark for their outstanding contributions during 1999.

Marcel J. Tremblay
President and Chief Executive Officer
Calgary, March 15, 2000

2000 Objectives

THE FUND WILL CONTINUE TO FOCUS on strengthening its asset base in 2000 through strategic acquisitions, improving cost efficiencies and following a prudent capital development plan. In addition, EnerMark will continue its on-going rationalization program to divest of non-core, short life properties thereby improving the operations of the Fund.

2000 Cash Available for Distribution

The Fund's Board of Trustees has established a base distribution rate of $0.06 per Unit per month with distribution of additional available cash to be considered on a quarterly basis. The Fund has set a production target of 21,300 BOE/d, before inclusion of any additional production that will result from the successful acquisition of Pursuit Resources Corp. At this targeted production level, it is expected that the base distribution of $0.06 per month can be achieved at a WTI reference price of approximately $22.00 US per barrel for oil, an AECO "C"/NIT reference price of $2.80 per Mcf for natural gas and a US to Canadian dollar exchange rate of $0.69.

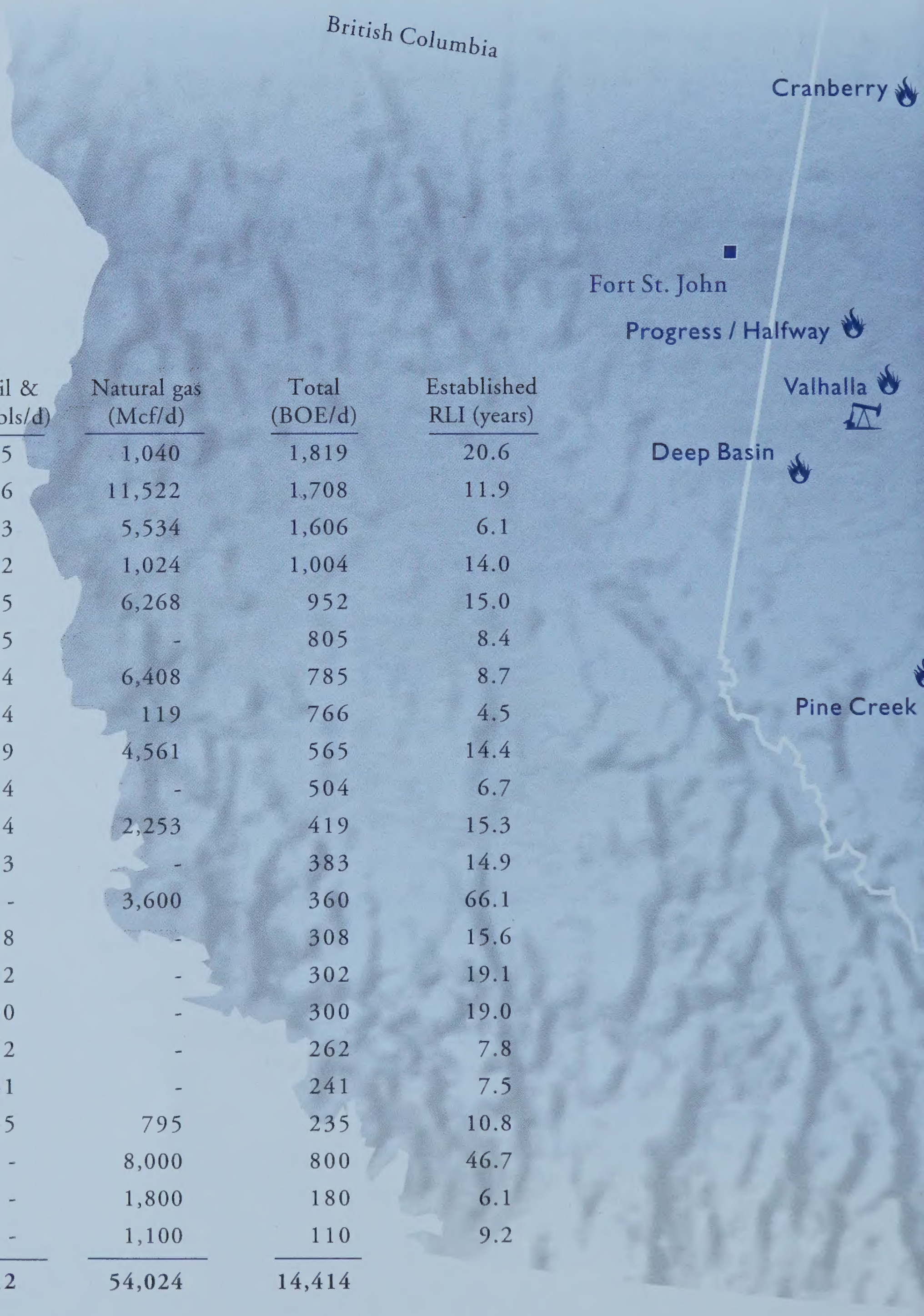
The following table outlines the expected sensitivities of available cash on a per unit basis to changes in the underlying reference prices and exchange rate.

Factor	Variance	Impact
Crude oil and NGLs price	±US$1.00 WTI/bbl	±1.6¢/Unit
Natural gas price	±Cdn $0.10 AECO "C"/NIT	±1.3¢/Unit
$US/$Cdn exchange rate	±US$0.01	±0.8¢/Unit

During the past year, we have experienced significant volatility in oil and natural gas prices, with a recent high for oil in excess of $34.00 US WTI per barrel. The Board plans to apply a portion of cash flow generated as a result of the current high oil and natural gas prices toward debt reduction to maintain the Fund's strong financial position.

As a result of the successful acquisition of Pursuit Resources Corp. on April 3, 2000, EnerMark's production will increase by approximately 4,540 BOE/day. The production and operating cash flows of Pursuit have been added to the Fund from that date and will be accretive to Fund Unitholders on a per Unit basis.

key producing Properties



1999 Production

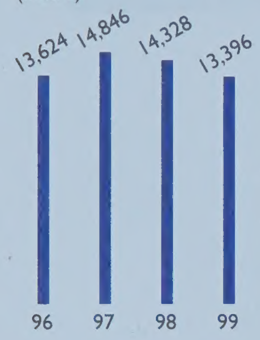
Area	Crude oil & NGLs (bbls/d)	Natural gas (Mcf/d)	Total (BOE/d)	Established RLI (years)
Giltedge	1,715	1,040	1,819	20.6
Deep Basin	556	11,522	1,708	11.9
Valhalla	1,053	5,534	1,606	6.1
Medicine Hat	902	1,024	1,004	14.0
Pine Creek	325	6,268	952	15.0
Little Horse	805	-	805	8.4
Progress	144	6,408	785	8.7
Utikuma	754	119	766	4.5
Cranberry	109	4,561	565	14.4
David	504	-	504	6.7
Kaybob South	194	2,253	419	15.3
Chauvin South	383	-	383	14.9
Bantry/Verger	-	3,600	360	66.1
Tatagwa	308	-	308	15.6
Battle Creek	302	-	302	19.1
Gift Lake	300	-	300	19.0
Heward	262	-	262	7.8
West Kingsford	241	-	241	7.5
Malmo	155	795	235	10.8
Hanna Garden	-	8,000	800	46.7
Taber	-	1,800	180	6.1
Thornbury	-	1,100	110	9.2
Total Key Producing Properties	9,012	54,024	14,414	


Gas Production
Oil Production
Recent Acquisitions
Alberta
Saskatchewan
Thornbury
Utikuma
Gift Lake
Little Horse
Kaybob South
Cherhill
Edmonton
Goldenspike
Giltedge
Chauvin South
Malmo
David
Saskatoon
Court
Hanna Garden
Calgary
Heward
Regina
Bantry /Verger
Tatagwa
Medicine Hat
Battle Creek
W. Kingsford
Taber

summary of Operations

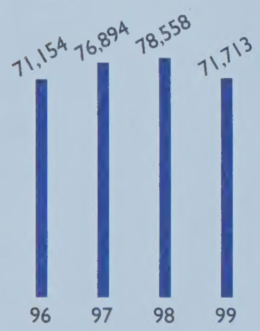
Oil & NGLs Production

(bbls/d)



Natural Gas Production

(Mcf/d)



AS THE PRICE OF OIL DECLINED TO 15 year lows throughout 1998 and into the first quarter of 1999, EnerMark set a production target of 20,870 BOE/d for 1999. This target was established based on a capital program primarily focused on developing and placing additional natural gas production on stream. A number of natural gas projects, such as Valhalla and Golden Spike, that were scheduled to come on in the first quarter experienced significant delays and were actually placed on stream in the third and fourth quarters.

EnerMark took advantage of the strength in natural gas asset prices by divesting of non-core natural gas properties at Calling Lake, Glacier, Soars and Campbell Namao in the first half of 1999. This resulted in the sale of approximately 675 BOE/d with total proceeds of $17.0 million.

The dramatic improvement in crude oil prices during the last nine months of 1999 provided the opportunity for EnerMark to initiate a number of oil projects that had been deferred for over a year. In the third quarter, EnerMark commenced its plans to drill at David, Fenn West and St. Anne. The Fund's main oil development project at Giltedge was delayed pending the completion of an impact study on the Battle River floodplain within the Giltedge field area. This study was completed in December of 1999 and it is expected that drilling will commence in the first quarter of 2000 adding approximately 600 bbls/d of oil net to EnerMark.

Despite the combined effect of the onstream delays of some of the Fund's key development projects and the property divestment program, EnerMark was still able to achieve an actual production rate of 20,567 BOE/d during 1999. This rate was 1.5% less than the targeted production level of 20,870 BOE/d set for the year.

EnerMark's operating costs for 1999 remained virtually unchanged from 1998 at $4.96/BOE, approximately 4% below the $5.15/BOE forecast for 1999.

Giltedge, Alberta - operated property - 100% W.I.

IMPROVED OIL PRICES THROUGHOUT 1999 resulted in an increase of 300% in the netback price for crude oil produced at Giltedge. The recovery in prices, combined with a production increase achieved as a result of a reservoir management program caused crude oil production to exceed 1998 exit rates and resulted in record levels of cash flow. Cash flow was further supplemented through the recompletion of the Colony zone in an existing well which provided a significant increase in natural gas production.

With the attractive current economic environment, additional infill development will proceed. A total of 14 wellsites were surveyed late in the third quarter of 1999. EnerMark was unable to obtain regulatory approval to drill on the majority of these sites until it completed an impact assessment of locating wellsites within the Battle River floodplain. This assessment was completed in December 1999 and approval for these locations is anticipated in the first quarter of 2000. Work was initiated on the infrastructure required to accommodate the increased production volumes anticipated from this drilling program and the majority of the wells are expected to be completed by the end of the second quarter of 2000. It is anticipated that this infill program will provide incremental oil production of 600 bbls/d net to the Fund. Giltedge produced an average of approximately 1,715 bbls/d of oil and 1.0 MMcf/d of natural gas during 1999.

Medicine Hat Glauc. "C" Pool, Alberta - operated property - 59% W.I.

IN 1999, ENERMARK AND ITS PARTNERS initiated a development plan to unitize and implement a waterflood recovery scheme. Throughout 1999, both the challenges of unitizing and developing a viable waterflood project were concluded with partners. It is anticipated that all necessary approvals and agreements will be obtained and that the necessary facilities will be in place in time to implement the waterflood in the third quarter of 2000. Production for 1999 from this pool averaged 1,004 BOE/d. The incremental recoverable oil anticipated through a successful waterflood could reach 8.3 million barrels gross (4.9 million barrels net).

Cherhill Unit No. 1, Alberta - operated property - 48.6% W.I.

CHERHILL UNIT NO. 1 WAS REJUVENATED in 1999 from a marginal Banff crude oil property producing less than 160 BOE/d gross (78 BOE/d net) to a natural gas property producing 420 BOE/d gross (205 BOE/d net). In mid-1999, EnerMark received approval from the Energy Utilities Board to produce the associated gas concurrently with the oil. The Unit had the necessary facilities in place to produce in excess of 3.5 MMcf/d of natural gas and production commenced shortly after approval was received. The Unit is expected to continue to produce approximately 3.5 MMcf/d gross (1.7 MMcf/d net) of natural gas, recovering in excess of 9.5 Bcf gross (4.6 Bcf net) over the next eight years. EnerMark is currently evaluating various compression optimization opportunities to maximize the recovery of these reserves.

Golden Spike, Alberta - operated property - 47.5% W.I.

THIS GAS WELL LOCATED APPROXIMATELY 30 KM west of the city of Edmonton was originally scheduled to come on stream in the second quarter of 1999 through a newly contracted third party gas plant designed to handle sour gas. Due to various delays with plant construction, the well was placed on stream in October of 1999. The plant experienced numerous start up problems and the full producing potential of this well was never achieved in 1999. It is anticipated that the well's capability of 3.0 MMcf/d gross (1.4 MMcf/d net) will be realized in the coming year as the plant is now operating on a continuous basis.

Valhalla, Alberta - operated property - 33.7% W.I.

ENERMARK DEVELOPED ADDITIONAL Halfway gas production from two projects located in the Valhalla area during 1999. During the first quarter, EnerMark placed a 60% working interest well on stream. This well is capable of producing 2.0 MMcf/d of natural gas and 60 bbls/d of associated liquids. The Fund is finalizing plans to place one more Halfway well in this area on stream in 2000. It is anticipated that this 100% working interest well will produce approximately 1.0 MMcf/d of natural gas and 30 bbls/d of natural gas liquids. In the fourth quarter of 1999 EnerMark recompleted and tied in a Halfway gas well on a separate prospect. This well commenced production at 1.5 MMcf/d gross (0.5 MMcf/d net) with liquids production of 15 bbls/d net. An additional development drilling opportunity on this play was farmed out to an industry partner and drilled at no cost to the Fund. This well was placed on stream in the third quarter at a rate of 0.3 MMcf/d. In 2000 EnerMark will initiate plans to develop additional natural gas in the area by developing the shallow Doe Creek gas producing zone.

Verger, Alberta - operated property - 16% W.I.

A 76 WELL DEVELOPMENT DRILLING program was initiated in October on this shallow gas property acquired in June of 1999. All 76 wells were successful with the completion and tie-in portions of the project to be completed in the first quarter of 2000 when additional compression facilities will be added, providing a total of 15 MMcf/d of capacity.

It is anticipated that this development project will more than double current production rates such that total production from this property will exceed 14 MMcf/d gross or 2.2 MMcf/d net to the Fund. Additional development drilling potential will be pursued in future years to optimize facility capacity and the recovery of the 83.8 Bcf (13.4 Bcf net) reserve base attributed to this asset. EnerMark has identified the potential to drill an additional 50 wells under a full development scenario of one well per 80 acres.

Drilling and Development Activities

IN 1999, ENERMARK PARTICIPATED in the drilling of 105 gross development wells (19.6 net) for an average working interest of 18.7%.

		Gross	Net
Development wells:	Oil	4	3
	Gas	97	15
	Dry	4	2
	Total	105	20
	Success ate	97%	90%
Farm out wells:	Oil	12	
	Gas	19	
	Dry	8	
	Total	39	
	Farm out success rate	79%	

Land Base

ENERMARK CONTINUED TO IMPROVE ITS developed and royalty land inventory in 1999, and reduced its undeveloped land base through farm out arrangements, sales, and lease expiries. Undeveloped land inventory decreased by 143,213 net acres in 1999 to 210,208 net acres due to lease expiries, sales and farm out arrangements. Continued exploitation of this undeveloped land base throughout 1999 resulted in 39 farm out wells drilled at no cost to the Fund, 79% of which were successful. Many of the farm out well arrangements ensured that the Fund would retain a royalty interest in the land. As a result, EnerMark currently has 482,548 acres of land under royalty arrangements.

Due to divestments of non-core properties, the Fund's net developed acreage decreased slightly from 1998. However, subsequent to year end, several acquisitions were concluded which added to the developed and undeveloped land base resulting in an increase in both inventories relative to 1998.

Land Inventory		**Developed**		**Undeveloped**	
Area	Royalty Acres	Gross Acres	Net Acres	Gross Acres	Net Acres
Alberta	335,713	1,107,402	198,849	369,045	135,141
British Columbia	47,591	207,280	21,866	104,604	35,000
Saskatchewan	99,143	68,762	25,586	75,475	39,620
Manitoba/NWT	101	2,621	417	1,232	447
Hanna Garden[1]	-	80,415	58,060	64,315	41,191
Western Star[1]	-	131,194	27,093	166,430	26,237
Total	**482,548**	**1,597,674**	**331,871**	**781,101**	**277,636**

[1] The Hanna Garden properties were added December 31, 1999 and the Western Star acquisition was effective January 7, 2000.

acquisitions & Divestments

DURING THE FIRST HALF OF 1999, commodity prices and market valuations remained low and acquisition activity continued to be depressed. EnerMark took advantage of this soft market and in May acquired an oil property producing 850 bbls/d in the David area of Alberta for $3.7 million or $4,470 per daily barrel. Following this, in June EnerMark acquired a 20% working interest in the natural gas properties of Derrick Energy Corporation at a net cost of $2.9 million. The Derrick acquisition provided the framework for an aggressive shallow gas infill drilling program which culminated in the successful drilling of 76 gross wells in late 1999 and set the stage for continued shallow gas development drilling in the coming years.

Subsequent to year-end, EnerMark successfully completed two additional major acquisitions - Western Star Exploration and a large natural gas property called Hanna Garden. These acquisitions have added over 1,600 BOE/d of natural gas production and 14,660 MBOE of established reserves to the Fund. Total acquisitions inclusive of the Hanna Garden properties and Western Star assets consisted of 18.6 million BOEs of established reserves at a cost of $75 million and over 2,600 BOE/d of production, 65% of which is natural gas.

Although oil properties were out of favour for most of 1999, the demand for natural gas properties was high and EnerMark took the opportunity to divest of 2,756 MBOE of natural gas reserves at a price of $6.17/BOE, generating proceeds of $17 million to the Fund. The divested properties were producing approximately 675 BOE/d consisting of primarily high decline and shut-in natural gas wells. The net effect of acquisitions and dispositions, including Hanna Garden and Western Star, was the addition of 15.8 million BOEs at a net cost of $3.68/BOE.

Established Reserve Additions - Historical Cost Summary

	Net Cost ($thousands)	Net Reserves Added (MBOE)	% of Production	Cost ($/BOE)
1996	$81,669	17,547	308%	$4.65
1997	145,072	24,588	299%	5.90
1998	56,516	11,630	144%	4.86
1999*	80,866	17,495	233%	4.62
4 year average			**241%**	**$5.11**

* includes Western Star and Hanna Garden acquisitions

David, Alberta

IN MAY OF 1999, ENERMARK PURCHASED 1,160 acres of land in the David heavy oil property which included 18 Lloydminster zone oil wells producing 850 bbls/d net to the Fund. The timing of this property purchase coincided with the improvement in oil prices, resulting in a 300% improvement in cash flow by year end. Development drilling plans were initiated in the fourth quarter of 1999 with the drilling of two successful infill wells occurring in the first quarter of 2000. Incremental production from these wells is 125 bbls/d and as a result of theses successes, EnerMark will be assessing additional infill drilling potential for 2000.

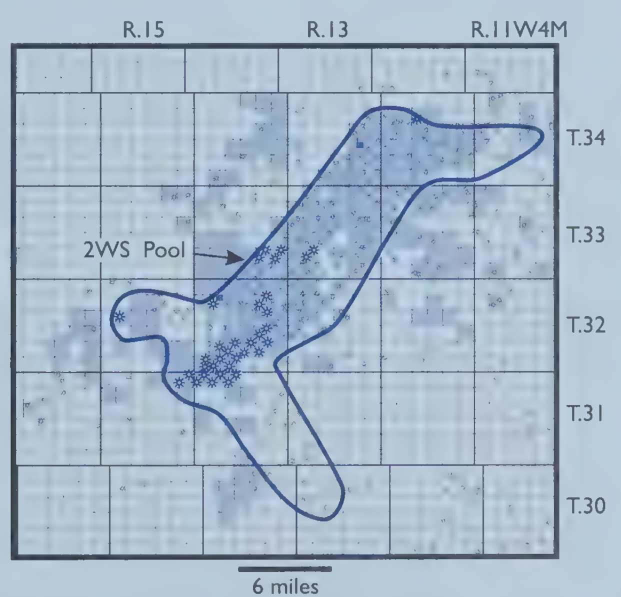
Derrick Energy

ON JUNE 4, ENERMARK SUCCESSFULLY concluded the acquisition of Derrick Energy Corporation, an Alberta-based natural gas company with assets comprised of 41 Bcf of established reserves, daily production of 7.5 MMcf/d with a 15.2 year reserve life index. This acquisition was allocated among The Enerplus Group with EnerMark acquiring 20% of these assets at a net cost of $2.9 million. The assets

are located in the Bantry, Princess and Verger areas in Southeastern Alberta which directly offset existing lands owned by The Enerplus Group and offer excellent synergy that is expected to reduce operating and administrative costs in these areas. In addition, the Derrick assets offer significant low risk, infill drilling opportunities. EnerMark identified 145 potential infill drilling locations and 76 of these were drilled in the last quarter of 1999. As a result, current production from the properties is 2.6 MMcf/d net to the Fund.

Western Star Exploration and the Hanna Garden Property

ON JANUARY 7, 2000 ENERMARK ACQUIRED Western Star Exploration Ltd. for a total consideration of $28.0 million. Western Star's assets are comprised primarily of natural gas properties currently producing 780 BOE/d concentrated in the Hanna, Taber and Thornbury areas of Alberta. EnerMark's estimate of Western Star's proven reserves total 36.9 Bcf of natural gas and 147 MBOE of crude oil and natural gas liquids. On an established basis, the reserves total 4,345 MBOE with an established reserve life index of 17.1 years. These reserve volumes include the results of a successful 21 well natural gas development program at Hanna Garden. Additionally a significant number of low risk, infill natural gas drilling opportunities have been scheduled for 2000.



Based on the strengths and future potential exhibited in the Hanna Garden property, EnerMark pursued the acquisition of the remaining working interests. Effective December 31, 1999, EnerMark acquired those interests from an affiliate of a major Canadian Pension Fund. The total purchase price for the property was $34.7 million which was comprised of $13.0 million cash and 6,050,000 EnerMark Trust Units. Included in the purchase were 103 Bcf of established natural gas reserves currently producing 9 million cubic feet per day. The property is 80% operated with low operating costs of $4.25/BOE and a very attractive netback of $20.00 per BOE. EnerMark plans to pursue a significant number of infill drilling opportunities to maximize production from this area.

reserves Summary

AS A RESULT OF SUCCESSFUL ACQUISITIONS concluded throughout 1999 and early 2000, the Fund replaced 233% of its daily production and 109% of its established reserves. The following tables reflect EnerMark's reserves of crude oil, natural gas and NGLs which have been evaluated by Sproule Associates Limited. This firm of independent petroleum engineers has evaluated and audited 84% of the Fund's year end total reserves. All evaluations of future net production revenues set forth in the tables are stated without any provision for income taxes, general and administrative costs and management fees. Probable reserves and values have been reduced by a factor of 50% to account for risk.

Reserves Summary

	Crude Oil (Mbbl)	Natural Gas (MMcf)	NGLs (Mbbl)	BOE (MBOE)	NPV 12% ($000)
Total established reserves as at December 31, 1998	57,125	384,745	10,634	106,233	$ 510,962
Proven, producing	33,261	211,900	5,772	60,223	377,365
Proven, non-producing	12,104	93,271	1,591	23,022	93,652
Total proven	45,365	305,171	7,363	83,245	471,017
Probable @ 50%	10,899	59,389	1,478	18,316	47,214
Total established reserves at December 31, 1999	56,264	364,560	8,841	101,561	$ 518,231
Hanna Garden acquisition effective December 31, 1999	-	103,147	-	10,315	49,515
Western Star acquisition effective January 7, 2000	144	41,847	16	4,345	30,392
Grand Total	**56,408**	**509,554**	**8,857**	**116,221**	**$ 598,138**

Reserves Reconciliation

	Crude Oil (Mbbl)		Natural Gas (MMcf)		NGLs (Mbbl)		Total MBOE		Established MBOE Prov. & 50% Prob.
	Prov.	Prob.	Prov.	Prob.	Prov.	Prob.	Prov.	Prob.	Prob.
Opening Reserves at December 31, 1998	48,065	18,120	328,262	112,966	8,888	3,492	89,779	32,908	106,233
Production	(4,167)	-	(26,175)	-	(723)	-	(7,508)	-	(7,508)
Divestments	(183)	(291)	(19,893)	(8,768)	-	-	(2,172)	(1,168)	(2,756)
Acquisitions	2,356	-	12,264	6,991	-	-	3,582	699	3,932
Drilling and development	1,370	95	5,142	1,470	81	18	1,965	260	2,095
Revisions	(2,076)	3,873	5,571	6,119	(883)	(554)	(2,401)	3,932	(435)
Reserves at December 31, 1999	45,365	21,797	305,171	118,778	7,363	2,956	83,245	36,631	101,561
Hanna Garden acquisition effective December 31, 1999	-	-	91,915	22,464	-	-	9,192	2,246	10,315
Western Star acquisition effective January 7, 2000	131	26	36,855	9,983	16	-	3,833	1,024	4,345
Grand Total	**45,496**	**21,823**	**433,941**	**151,225**	**7,379**	**2,956**	**96,270**	**39,901**	**116,221**

Present Worth of Production Revenue (including ARTC)

As at December 31, 1999, Present Worth Discounted at ($millions)	10%	12%	15%
Proven producing	$ 409.1	$ 377.4	$ 339.5
Proven non-producing	107.4	93.6	77.2
Total proven	516.5	471.0	416.7
Probable at 50%	56.0	47.2	37.5
Total established reserves	$ 572.5	$ 518.2	$ 454.2
Hanna Garden acquisition effective December 31, 1999	58.0	49.5	40.2
Western Star acquisition effective January 7, 2000	34.0	30.4	26.2
Total established reserves	$ 664.5	$ 598.1	$ 520.6

Net Asset Value

($million, except per Unit amounts)	1999	1998
Present value of established reserves discounted at 12% at December 31, 1999	$ 518.2	$ 511.0
Hanna Garden acquisition effective December 31, 1999	49.5	-
Western Star acquisition effective January 7, 2000	30.4	-
Undeveloped acreage and seismic	21.0	28.1
Net debt (1)	(176.1)	(185.5)
Net asset value	$ 443.0	$ 353.6
Net asset value per Unit (2)	$ 3.36	$ 3.30

(1) Includes net debt at Dec. 31, 1999 plus net debt assumed with acquisition of Western Star and cash consideration paid for Hanna Garden acquisition.

(2) Based on year end Units outstanding of 125,786,000 plus Units issued with respect to Western Star and Hanna Garden acquisitions of 6,123,000.

Pricing Assumptions

THE PRESENT VALUE OF FUTURE CASH flow at December 31, 1999 was based upon crude oil and natural gas pricing assumptions prepared by Sproule Associates Limited. These forecasts are adjusted for reserve quality, transportation charges and the provisions of any applicable sales contracts.

	Crude Oil		Natural Gas	
Year	WTI Cushing Oklahoma $US/bbl	Light Crude (1) Edmonton $Cdn/bbl	30 Day Spot Plant Gate Price $Cdn/MMbtu	$US/Cdn Exchange Rate
2000	20.00	27.51	2.79	0.70
2001	20.30	27.13	2.68	0.72
2002	20.60	27.15	2.65	0.73
2003	20.91	27.56	2.69	0.73
2004	21.23	27.98	2.73	0.73

Escalation rate of 1.5% per year thereafter

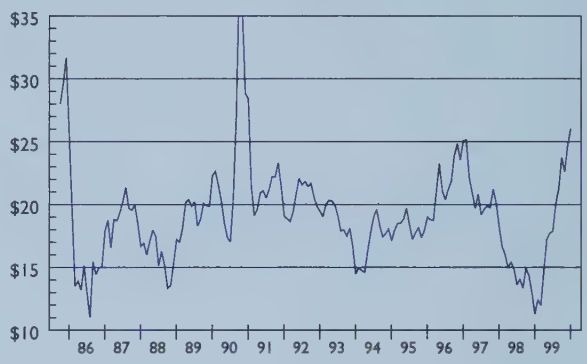
(1) Edmonton refinery postings for 40° API, 0.4% sulphur content crude

marketing Arrangements

Crude Oil

Historical
WTI Price

($US per barrel)

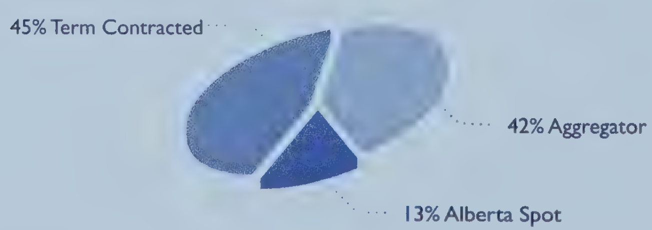


1999 MARKED A YEAR OF SIGNIFICANT volatility and change for crude oil prices. West Texas Intermediate Crude Oil (WTI) started the year trading at record lows around $12 US/bbl and ended up on Dec. 31, 1999 at $25.60 US/bbl. Overall, the average WTI price increased by 33.5% from $14.41 US/bbl in 1998 to $19.24 US/bbl during 1999. Commencing at the end of the first quarter of 1999, global inventories of crude oil and related petroleum products began their dramatic decline to record lows. The decline in inventories was caused by i) oil production cutbacks by OPEC nations, ii) declining production from non-OPEC countries due to reductions in drilling resulting from the oil price collapse in 1998, and iii) increases in demand for petroleum products due to the strengthening world economy.

The Fund received a weighted average wellhead price of $22.39 Cdn/bbl for its production of light, heavy, and medium crudes. This year's wellhead price increased 48% from the 1998 level of $15.16 Cdn/bbl due to the higher underlying WTI benchmark price and also to more favourable pricing for the Fund's heavy oil production.

EnerMark produced approximately 4,000 bbls/d of heavy oil in 1999. The quality differential adjustment for these heavy volumes was significantly lower for the first two quarters of 1999 as heavy oil supply and demand was negatively impacted by the low WTI price. As prices improved, heavy oil differentials returned to more normal levels in the latter part of the year. Nevertheless, the Fund's overall netback relative to WTI showed significant improvement from 1998.

1999 Natural Gas Contracts



Natural Gas

THE PAST YEAR MARKED THE FIRST PERIOD of significant surplus export capacity for Canadian natural gas flowing to the U.S. market. The current surplus can be attributed to i) Canadian natural gas export capacity increased substantially at the end of 1998 as a result of the expansion of the TransCanada and Northern Border pipeline systems, and ii) low oil prices in 1998 and early 1999 eroded the amount of cash flow available to the industry for reinvestment and as a consequence, the reduced drilling activity dramatically slowed the growth of western Canadian natural gas production.

The resulting impact of this surplus capacity was an upward movement of western Canadian natural gas prices toward levels received in the U.S. markets. This is evidenced by the fact that spot natural gas prices on the NYMEX increased by only 7% in 1999 while the Alberta spot price increased by 45% to $2.92/Mcf. Looking forward into 2000, the export surplus is expected to grow as the Alliance pipeline construction is completed and comes on stream toward the end of the year. Many analysts are currently projecting that Canadian pipeline capacity will exceed the available supply for the foreseeable future. As a result, Canadian natural gas prices should continue to trade more closely with the historically higher priced U.S. market.

The U.S. natural gas market has strengthened in recent months due to declining inventory levels resulting from the combination of a normal North American winter in 1999 and increased demand as industrial users switch from higher priced fuel sources. In addition, drilling activity levels have also declined in the U.S. putting downward pressure on productivity which should create a strong market during 2000. EnerMark remains optimistic regarding natural gas prices and continues to position itself strategically to benefit from this commodity in the future. Our optimism is reflected in the natural gas futures market where five year contracts for delivery within Alberta are trading in the $3.50 per gigajoule range.

EnerMark's diverse portfolio of contractual arrangements generated an average netback field price of $2.31/Mcf in 1999, a 20% increase over 1998 levels. EnerMark will benefit from future price increases on its Alberta spot contracts as well as on it sales to the major aggregators, TransCanada, PanAlberta Gas and Progas Ltd., which provide a unique portfolio of contracts with a broad continental downstream exposure. Also, in order to provide a level of revenue certainty and stability, EnerMark has entered into a number of fixed price contracts that will yield $2.40/Mcf on 16.5 MMcf/d of the Fund's 2000 natural gas production.

Revenue % by Source	1999	1998	1997	1996
Natural gas	36%	41%	30%	23%
Crude oil	58%	51%	61%	69%
NGLs	6%	8%	9%	8%
	100%	100%	100%	100%

Commodity Price Risk Management

THE FUND HAS AN ACTIVE COMMODITY PRICE risk management review process in place and continues to seek opportunities to safeguard both its oil and natural gas revenue streams from potential adverse swings.

For 2000, the Fund has a crude oil price contract in place for 1,750 bbls/d that sets a minimum floor protection level of $26.50 (CAD denominated WTI equivalent) with participation up to $30.60 Cdn.

In addition, EnerMark has entered into a Revenue Protection Plan for each of the 2nd, 3rd and 4th quarters of 2000 that will ensure a minimum level of revenue on approximately 29% of the Fund's current production. This arrangement provides maximum flexibility by allowing the Fund to retain 100% of any pricing upside above an established floor level. The Plan will apply on a quarterly basis and will guarantee that the Fund will receive a minimum combined benchmark price of Cdn $31.40 per barrel of oil equivalent on production of 6,000 barrels of oil equivalent per day (comprising 4,000 barrels per day of crude oil and 20.0 million cubic feet per day of natural gas). Under the terms of the contract, the minimum benchmark prices are based on a West Texas Intermediate crude oil price of US $23.00 per barrel (Cdn $33.10 per barrel) and an Alberta spot price for natural gas of Cdn $2.80 per thousand cubic feet. The total cost of this plan amounts to $583,300 per quarter or approximately 0.5 (one half) cents per quarter per outstanding Trust Unit.

The Fund will continue to seek opportunities to effectively manage commodity price risk for acquisitions and specific price sensitive development projects.

environment & Safety

ENERMARK RECOGNIZES THAT an effective Environment and Safety Management Program will result in the protection of the environment and the health and safety of all persons and communities affected by and involved in its activities. The prevention of losses to people, equipment, materials and damage to the environment is a combined effort of the Fund and its employees. EnerMark strives to continually improve its programs to meet the growing challenges faced by oil and gas operations in Western Canada.

Employee Training

OPERATIONAL AND ENVIRONMENT AND Safety training for EnerMark staff and operators are key components of EnerMark's Environment & Safety programs.

EnerMark has developed the Job Performance Management System (JPMS), a comprehensive approach to planned development and progression of field operations personnel as well as managing risk in EnerMark's field operations. All field areas and district offices have the JPMS available as a key reference resource for job procedures, policies, and corporate Emergency Response Plan information and government regulations. In addition, the Employee Competence Tracking System is a key component of the JPMS and provides the means to manage an employee's progress and measure the overall effectiveness of the program. With this program, EnerMark ensures that employees and contract operating personnel are properly prepared at all times to carry out their tasks safely, responsibly and effectively.

All new or transferred employees and summer students working in the field go through an orientation program prior to working in that area. The program is designed to provide the new personnel with the required training and familiarize them with the operations and hazards associated with their responsibilities.

EnerMark's Environment and Safety department members regularly take courses in Occupational Health and Safety, due diligence, environmental regulation, site remediation and waste handling, in order to continually improve our E & S programs.

Acquisition Due Diligence Investigations

ENERMARK TAKES A PRO-ACTIVE APPROACH to the investigation of existing environmental liabilities when acquisition opportunities are being evaluated. Potential soil and ground-water issues are identified at this stage to help protect the Fund from purchasing properties with significant environmental liabilities. In 1999, the Verger, Bantry and David purchases were investigated and no material environmental liabilities were noted.

Site Inspections Program

AS PART OF ITS DUE DILIGENCE PROGRAM, EnerMark conducts both internal and third party site inspections at selected facilities each year. The program consists of inspections conducted by third party safety or environmental consultants or an internal team that consists of E & S staff, Operations staff, and field foremen or operators. In total, 14 operated properties and two non-operated properties were inspected in 1999 with no material issues identified by these inspections.

management's Discussion & Analysis

Revenue

GROSS REVENUES WERE $169.5 MILLION for the year ended December 31, 1999 versus $134.1 million for the year ended December 31, 1998. Significant increases in commodity prices for 1999 as compared to 1998 more than offset lower production volumes. The average crude oil and NGLs price, before hedging, of $22.39/bbl was $7.23/bbl or 48% higher than the 1998 price of $15.16/bbl. Natural gas averaged $2.31/Mcf, before hedging, which was $0.39/Mcf or 20% higher than the price in 1998 of $1.92/Mcf. In 1999 the Fund implemented a commodity hedging program which reduced oil and natural gas revenues by $0.2 million or 3 cents per BOE. Including the effects of the hedging program, oil and NGLs prices averaged $22.21/bbl and natural gas prices averaged $2.33/Mcf for the year. Crude oil and NGLs production for 1999 averaged 13,396 bbls/d, down 7% from the 1998 average of 14,328 bbls/d. Natural gas averaged 71,713 Mcf/d during 1999 which was 9% lower than the 1998 average of 78,558 Mcf/d. Interest and other income decreased in 1999 by $7.1 million, primarily because 1998 included interest earned on U.S. dollar term deposits held during the year and related foreign exchange gain realized when these deposits were converted into Canadian dollars. In addition, 1998 included fees earned with respect to seismic and option rights granted in respect to undeveloped oil and gas interests to third parties.

The following table analyzes the changes in gross crude oil and natural gas revenues over the past year:

($millions)	Crude Oil & NGLs Revenues	Natural Gas Revenues	Other Revenues	Total	Percent Change	Crude Oil & NGLs/ Gas Ratio
1998 gross revenues	$ 79.3	$ 55.2	$ (0.4)	$ 134.1	-23%	59:41
Increase (decrease)						
Volume variance	(5.5)	(4.8)	-	(10.3)		
Price variance	35.7	10.0	0.0	45.7		
	30.2	5.2	0.0	35.4		
1999 gross revenues	**$ 109.5**	**$ 60.4**	**$ (0.4)**	**$ 169.5**	**+26%**	**64:36**

Expenses

THE NET ROYALTY RATE FOR 1999 increased marginally by 0.5% to 19% over 1998 levels. Royalty expense, net of ARTC, increased by $7.3 million or 29% as a consequence of the higher oil and NGL prices. Operating expenses were $37.2 million in 1999 compared to $40.4 million for 1998 due to the lower production volumes. On a BOE basis, operating expenses decreased marginally to $4.96 per BOE in 1999 from $4.99 per BOE in 1998.

General and administrative costs expensed increased slightly by $0.1 million or 2.2% to $5.7 million. On a BOE basis the increase was 10% to $0.76 per BOE due to lower production volumes in 1999 versus 1998. Management fees increased by $0.7 million or 45% as a result of higher oil and gas operating income.

Interest expense decreased by $0.7 million to $9.1 million in 1999 due to lower average outstanding bank debt, offset in part by higher interest rates applicable to borrowings in 1999 over 1998.

Depletion, depreciation and amortization declined by $7.1 million or 10% in 1999 due to the addition of proven reserves at a cost below the depletion rate in 1998 and a decrease in production volumes. The charge for depletion and amortization on a BOE basis decreased to $8.24 from $8.51 per BOE in 1998.

Funds Flow from Operations and Net Income

FUNDS FLOW FROM OPERATIONS INCREASED by $18.2 million or 28% to $82.1 million in 1999 due to higher crude oil and natural gas revenues, lower operating costs and lower interest expenses offset in part by higher royalties and a reduction in other income. 1998 funds flow from operations also included $6.1 million of prior years' ARTC recovery.

Net income increased by $16.9 million for 1999 due primarily to the increase in funds flow from operations supplemented by lower depletion, depreciation and amortization charges and a reduction in capital tax associated with the lower debt level. The increase in funds flow from operations was also offset in part by a lower deferred income tax recovery due to the increase in net income before taxes.

Cash Available for Distribution

IN VIEW OF THE SIGNIFICANT INCREASES in oil and natural gas prices in the latter part of 1999 and the increase in debt to fund the acquisition of Western Star and property interests in the Hanna Garden area of Alberta (refer to Note 10 to the Consolidated Financial Statements) the Board of Trustees determined to apply a portion of the cash otherwise available for distribution to debt reduction. Accordingly, in 1999 the Fund applied $3.9 million of cash, otherwise available for distribution, against payment of outstanding bank indebtedness which represented a payment equivalent to approximately $0.03 per Unit. Cash available for distribution, after providing for the debt repayment, increased by 12% to $78.2 million from $70.1 million in 1998, while on a per Unit basis, cash available for distribution was $0.64 for both years since there was a greater number of Trust Units outstanding during 1999.

Cash available for distribution is paid out by way of monthly cash payments to Unitholders on the 20th day of each month, with an adjustment at each quarter's end.

The following table analyzes changes in cash available for distribution over the past year:

($millions)	Crude Oil & NGLs Revenues	Natural Gas Revenues	Other	Expenses	Total
1998 Cash available for distribution					$70.1
Increase (decrease):					
Volume variance	$(5.5)	$(4.8)	$ -	$ -	$(10.3)
Price variance	35.7	10.0	-	-	45.7
Interest and other income	-	-	(7.3)	-	(7.3)
Royalties, net of ARTC	-	-	-	(7.3)	(7.3)
ARTC recovery, 1998				(6.1)	(6.1)
Operating, interest and other costs	-	-	-	3.4	3.4
Proceeds on sale of property, plant and equipment, 1998	-	-	(6.1)	-	(6.1)
Cash withheld for debt reduction, 1999	-	-	(3.9)	-	(3.9)
	$30.2	$5.2	$ (17.3)	$ (10.0)	$8.1
1999 Cash available for distribution					**$78.2**

Liquidity and Capital Resources

DURING 1999 THE FUND COMPLETED A rights offering which resulted in the issuance of 9,533,602 Trust Units at a price of $2.45 per Unit and a Trust Unit offering which resulted in the issuance of 7,000,000 Trust Units at a price of $3.80 per Unit. Combined proceeds of the offerings, net of issue expenses, was $48.0 million which was initially applied to reduce outstanding bank debt and ultimately used to finance the Fund's ongoing capital program and acquisition activities.

As at December 31, the Fund's capital structure was as follows:

	1999		1998	
($millions)	Amount	%	Amount	%
Trust Unit equity, at cost	$ 375.4	74%	$ 365.6	66%
Bank debt, net of working capital	134.5	26%	185.5	34%
Total	$ 509.9	100%	$ 551.1	100%

As at December 31, 1999 the Fund had an unused line of credit of $68.7 million (1998 - $16.0 million).

Capital Expenditure Funding

THE ONGOING CAPITAL EXPENDITURES of the Fund are financed through new issues of Trust equity, bank borrowing and funds flow from operations.

Bank loan principal payments, interest and capital expenditures are allowable deductions from cash otherwise available for distribution to Unitholders. During 1999, $3.9 million was withheld from cash available for distribution for reduction of debt. No comparable amount was withheld in 1998 and no amount was directly withheld for funding of capital expenditures in either year.

Net capital expenditures for the period amounted to $12.1 million (1998 - $56.5 million). Expenditures were incurred for property acquisitions of $8.3 million (1998 - $32.5 million) with drilling and facility construction accounting for $18.9 million (1998 - $32.2 million). Corporate expenditures amounted to $1.9 million (1998 - $1.3 million). Net divestments of undeveloped land, properties, facilities and seismic data amounted to $17.0 million (1998 - $9.5 million).

Income Taxes

THE FUND IS REQUIRED TO FILE AN income tax return on an annual basis. Any income otherwise taxable in the Fund is allocated to Trust Unitholders. Approximately 17 cents per Unit of the 1999 cash distribution was taxable for EnerMark Unitholders compared to 19 cents per Unit for 1998. As a percentage of total distributions per Unit, the taxable portions were approximately 27% and 32% respectively for 1999 and 1998.

The Fund qualifies as a mutual fund trust under the Canadian Income Tax Act and, accordingly, Units of the Fund are qualified investments for RRSPs, RRIFs and DPSPs.

The following is a general summary of the income tax consequences to a Unitholder who is a Canadian resident and holds the Units as a capital property:

- Unitholders are required to include in computing income their pro-rata share of any taxable income earned by the Fund in that year. Income of a Unitholder is considered income from property and not resource revenue.
- An investor's adjusted cost base ("ACB") in a Trust Unit equals the purchase price of the Unit less any non-taxable cash distributions received from the date of acquisition. To the extent a Unitholder's ACB in a Trust Unit is reduced below zero, such amount will be deemed to be a capital gain to the Unitholder and the Unitholder's ACB in the Trust Unit will be brought to $nil. In general, Unitholders will have a capital gain or a capital loss upon disposition of the Units.

The following table presents the taxable portion of cash distributions per Trust Unit:

		1999		1998	
Record date	Payment date	**Distribution**	**Taxable Portion**	Distribution	Taxable Portion
February 10	February 20	**$0.040**	**$0.0107**	-	-
March 10	March 20	**$0.030**	**$0.0080**	$0.075	$0.0239
April 10	April 20	**0.030**	**0.0080**	0.075	0.0239
May 10	May 20	**0.050**	**0.0134**	0.075	0.0239
June 10	June 20	**0.030**	**0.0080**	0.055	0.0176
July 10	July 20	**0.030**	**0.0080**	0.055	0.0176
August 10	August 20	**0.090**	**0.0241**	0.055	0.0176
September 10	September 20	**0.050**	**0.0134**	0.055	0.0176
October 10	October 20	**0.050**	**0.0134**	0.040	0.0127
November 10	November 20	**0.100**	**0.0267**	0.045	0.0144
December 10	December 20	**0.060**	**0.0160**	0.040	0.0127
December 31	January 20, 2000	**0.060**	**0.0160**	0.030	0.0096
Total amount		**$0.620**	**$0.1657**	$0.600	$0.1915

Risk Management

CERTAIN RISKS ARE ASSOCIATED WITH the finding, development, production and marketing of oil and gas products. In addition, the oil and gas industry is subject to federal and provincial government regulation.

Commodity pricing is another risk faced by energy companies such as EnerMark. A Risk Management Committee has been established to continually evaluate market conditions. The Committee meets on a monthly basis and makes recommendations concerning the forward sale of commodities, foreign exchange and bank interest rates. As of December 31, 1999, various crude oil and natural gas hedges were in place as more fully described in Note 9 to the Consolidated Financial Statements contained herein.

While EnerMark has no control over commodity pricing and changes in legislation, nor changes to the ARTC, the Fund has developed several strategies to mitigate these risks. For example, new property acquisitions must meet the following guidelines:

- Evaluated by independent engineers where the purchase price exceeds $5 million;
- Purchase price on a single transaction not to exceed present worth of estimated future net cash flow using a discount rate equal to the lesser of:
    - twice the yield on 10 year Government of Canada bonds, or
    - the yield on 10 year Government of Canada bonds plus 4% after deducting general and administrative expenses and incorporating the impact of debt financing, but before income taxes;
- Not more than 25% of the value of all oil and natural gas properties to be attributed to a single pool;
- Not more than 75% of the value of all oil and natural gas properties to be attributed to natural gas;
- Other guidelines must be approved by the Board of Trustees of the Fund and the Board of Directors of EnerMark Inc. from time to time.

Furthermore, the following strategies also help mitigate risk:

- Farm out exploratory or other high-risk drilling prospects;
- Participate in low risk development activities;
- Use reliable suppliers;
- Monitor pipeline and market conditions closely;
- Market products to a diverse range of buyers;
- Meet or exceed industry standards for liability insurance and purchase business interruption insurance for selected facilities where available;
- Keep abreast of current affairs to act quickly and pro-actively where possible; and
- Use the latest technology to improve all facets of business processes.

Year 2000 Status

THE FUND'S MANAGEMENT IS FULLY aware of the year 2000 issue and had formally established a Year 2000 Readiness Program to proactively mitigate potential serious exposure to the year 2000 issue. The plan has been outlined and followed as disclosed in the Company's 1998 annual report to Unitholders.

EnerMark's Year 2000 readiness activities have been completed on schedule including: completion of testing, remediation of non-compliant hardware and software, and contingency planning for systems and field operations identified as being critical to the business. To date, EnerMark has not experienced any year 2000 related issues and believes that the methodology adopted has and will continue to minimize the likelihood of any impact of year 2000 problems.

Costs associated with the Year 2000 Readiness program have been expensed or capitalized, depending on their nature. Costs incurred in 1999 for year 2000 remediation efforts were less than $150,000. Costs associated with the year 2000 remediation efforts to date have had no material effect on the financial position or results of operations.

While prudent measures have been taken to mitigate the risk associated with the year 2000 issue, there are dependencies on key business partners for provision of products and services. The Fund has no means of ensuring that key business partners and suppliers will not be affected in the future by the year 2000 issue.

financial Statements

Management's Responsibility

MANAGEMENT OF THE FUND IS RESPONSIBLE for the preparation of the consolidated financial statements for the EnerMark Income Fund and for the consistency, therewith, of all other financial and operating data presented in this annual report.

Management maintains a system of internal controls to provide reasonable assurance that all assets are safeguarded and to facilitate the preparation of relevant, reliable and timely information.

External auditors, appointed by the Fund's Board of Trustees, have examined the consolidated financial statements of the Fund. The Audit Committee, consisting of unrelated Trustees of the Fund, has reviewed these statements with management and the auditors, and has recommended their approval to the Board of Trustees. The Board of Trustees has approved the consolidated financial statements of the Fund.

Marcel J. Tremblay
President and Chief Executive Officer

Gordon J. Kerr
Gordon J. Kerr
Vice President Finance and Chief Financial Officer

auditors' Report

To the Unitholders of EnerMark Income Fund:

WE HAVE AUDITED THE CONSOLIDATED balance sheet of EnerMark Income Fund as at December 31, 1999, 1998 and 1997 and the consolidated statements of net income, accumulated income, accumulated distributions and for each of the periods in the three year period ended December 31, 1999. These financial statements are the responsibility of the Fund's Management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by Management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Fund as at December 31, 1999, 1998 and 1997 and the results of its operations and the cash flows of the periods in the three year period ended December 31, 1999 in accordance with generally accepted accounting principles.

PricewaterhouseCoopers LLP
Chartered Accountants
Calgary, Alberta
March 10, 2000

consolidated Balance Sheet

As at December 31 ($thousands)	1999	1998	1997
Assets			
Current assets			
Cash and short-term investments	$ 2,482	$ 1,682	$ 34,786
Accounts receivable	15,506	15,532	21,592
Other	1,365	638	3,550
	19,353	17,852	59,928
Property, plant and equipment	789,174	771,291	714,775
Accumulated depletion and depreciation	(232,889)	(174,743)	(109,528)
	556,285	596,548	605,247
Other Assets			
Deferred reorganization charges, net of amortization (*Note 3*)	1,263	2,273	3,283
Investments	-	1,208	1,745
	1,263	3,481	5,028
	$ 576,901	$ 617,881	$ 670,203
Liabilities and equity			
Current liabilities			
Accounts payable	$ 19,705	$ 17,863	$ 30,167
Payable to related company (*Note 3*)	2,852	1,462	4,218
	22,557	19,325	34,385
Bank debt (*Note 2*)	131,315	184,034	128,468
Deferred income taxes	33,593	36,550	50,167
Accumulated site restoration	14,035	12,411	10,731
	178,943	232,995	189,366
Equity			
Fund capital (*Note 4*)	592,693	538,004	548,706
Accumulated income	78,328	52,574	43,693
Accumulated distributions	(295,620)	(225,017)	(145,947)
	375,401	365,561	446,452
	$ 576,901	$ 617,881	$ 670,203

Signed on behalf of the Board:

Marcel J. Tremblay
Trustee

André Bineau
Trustee

consolidated
Statement of Net Income

For the year ended December 31 ($thousands)	1999	1998	1997
Revenues			
Oil and gas sales	$ 169,541	$ 134,102	$ 173,919
Crown royalties	(25,279)	(21,217)	(25,869)
Alberta royalty tax credit	1,377	1,471	1,387
Freehold and other royalties	(8,243)	(5,104)	(6,914)
	137,396	109,252	142,523
Interest and other income	1,045	8,099	4,062
Recovery of ARTC (*Note 8*)	-	6,081	-
	138,441	123,432	146,585
Expenses			
Operating	37,228	40,423	39,886
General and administrative	5,726	5,604	4,544
Management fee (*Note 3*)	2,204	1,516	2,338
Interest	9,078	9,731	5,092
Depletion, depreciation and amortization	61,857	68,932	72,006
	116,093	126,206	123,866
Net income (loss) before taxes	22,348	(2,774)	22,719
Capital taxes	1,551	1,962	1,868
Deferred income taxes (recovery) (*Note 5*)	(4,957)	(13,617)	(3,004)
	(3,406)	(11,655)	(1,136)
Net income	$ 25,754	$ 8,881	$ 23,855
Net income per Trust Unit	$ 0.22	$ 0.08	$ 0.24
Weighted average number of Trust Units outstanding during the period	118,679,631	109,507,194	100,023,159

consolidated
Statement of Accumulated Income

For the period ended December 31 ($thousands)	1999	1998	1997
Accumulated income, beginning of period	$ 52,574	$ 43,693	$ 19,838
Net income	25,754	8,881	23,855
Accumulated income, end of period	$ 78,328	$ 52,574	$ 43,693

consolidated
Statement of Cash Flows

For the year ended December 31 ($thousands)	1999	1998	1997
Operating activities			
Net income	$ 25,754	$ 8,881	$ 23,855
Depletion, depreciation and amortization	61,857	68,932	72,006
Deferred income taxes (recovery)	(4,957)	(13,617)	(3,004)
Gain on sale of investment	(565)	(267)	-
Funds flow from operations	82,089	63,929	92,857
Decrease (increase) in non-cash working capital	32	8,010	7,988
	82,121	71,939	100,845
Financing activities			
Issue of Trust Units (*Note 4*)	54,689	8,172	104,203
Repurchase of Trust Units (*Note 4*)	-	(18,874)	-
Cash distributions to Unitholders	(70,603)	(79,070)	(101,763)
Bank loan (payments) proceeds	(53,579)	55,566	50,823
	(69,493)	(34,206)	53,263
Investing activities			
Property, plant and equipment	(25,509)	(80,082)	(58,030)
Proceeds on sale of property, plant & equipment	16,957	9,468	45,824
Acquisition of subsidiary (*Note 7*)	(2,925)	-	(116,815)
Proceeds on sale of investments	773	804	(1,745)
Site restoration and abandonment	(1,124)	(1,027)	(351)
	(11,828)	(70,837)	(131,117)
Increase (decrease) in cash & short-term investments	800	(33,104)	22,991
Cash and short-term investments, beginning of period	1,682	34,786	11,795
Cash and short-term investments, end of period	$ 2,482	$ 1,682	$ 34,786
Supplementary cash information			
Cash income taxes paid	$ -	$ -	$ -
Cash interest paid	$ 9,001	$ 9,710	$ 4,941

consolidated
Statement of Accumulated Distributions

For the period ended December 31 ($thousands)	1999	1998	1997
Accumulated distributions, beginning of period	$ 225,017	$ 145,947	$ 44,184
Distributions	70,603	79,070	101,763
Accumulated distributions, end of period	$ 295,620	$ 225,017	$ 145,947

notes to Consolidated Financial Statements

FOR THE YEARS ENDED DECEMBER 31, 1999, 1998 and 1997 (tabular amounts shown in $thousands, except Unit and per Unit amounts).

1. Summary of Significant Accounting Policies

a. Organization

ENERMARK INCOME FUND (the "Fund") was formed for the purpose of effecting an arrangement under the Business Corporations Act (Alberta), involving, among other things, the exchange of Mark Resources Inc. ("Mark") securities for Units of the Fund (the "Arrangement"). The effective date of the Arrangement was April 3, 1996.

The Fund is an unincorporated investment trust governed by the laws of the Province of Alberta and created pursuant to a Declaration of Trust. The beneficiaries of the Fund (the "Unitholders") are holders of Trust Units issued by the Fund (the "Trust Units"). The Fund is a limited-purpose trust whose purpose is to invest in securities of its wholly-owned subsidiary EnerMark Inc. ("EnerMark"), invest in royalties granted by EnerMark, administer the assets and liabilities of the Fund and make distributions to the Unitholders all in accordance with the Declaration of Trust.

The Management of the Fund prepares its financial statements following accounting policies generally accepted in Canada. The following significant accounting policies are presented to assist the reader in evaluating these consolidated financial statements and, together with the following notes, should be considered an integral part of the consolidated financial statements.

b. Basis for Accounting

THE CONSOLIDATED FINANCIAL statements include the accounts of the Fund, EnerMark and EnerMark's subsidiaries. All transactions between the Fund, EnerMark and EnerMark's subsidiaries have been eliminated for purposes of these consolidated financial statements.

c. Property, Plant and Equipment - Oil and Gas

THE FUND FOLLOWS THE FULL cost method of accounting. All costs of acquiring oil and natural gas properties and related development costs are capitalized and accumulated in one cost centre. Maintenance and repairs are charged against earnings, and renewals and enhancements, which extend the economic life of the property, plant and equipment are capitalized. During 1999, general and administrative costs of $3,734,000 (1998 - $3,238,000, 1997 - $3,823,000) were capitalized. No interest expenses have been capitalized.

Gains and losses are not recognized upon disposition of oil and natural gas properties unless such a disposition would significantly alter the rate of depletion.

d. Ceiling Test

THE FUND PLACES A LIMIT on the aggregate cost of property, plant and equipment which may be carried forward for amortization against revenues of future periods (the "Ceiling Test"). The Ceiling Test is a cost recovery test whereby the capitalized costs less

accumulated depletion and site restoration are limited to an amount equal to estimated undiscounted future net revenues from proven reserves based on year-end prices, plus the unimpaired costs of non-producing properties, less estimated future general and administrative expenses, site restoration costs, management fees, financing costs and capital taxes. Future distributions to Trust Unitholders, whether or not they are required under the Trust Indenture, are not considered future financing costs for purposes of the ceiling test. Costs and prices at the balance sheet dates are used in determining ceiling test amounts. Any costs carried on the balance sheet in excess of the ceiling test limitation are charged to earnings.

e. Depletion and Depreciation

THE PROVISION FOR DEPLETION and depreciation of oil and natural gas assets is calculated using the unit of production method based on the Fund's share of proven reserves before royalties. Reserves are converted to equivalent units on the basis of approximate relative energy content.

f. Site Restoration and Abandonment

THE PROVISION FOR ESTIMATED site restoration costs is determined using the unit of production method and is included in the depletion, depreciation and amortization expense. Actual site restoration costs are charged against the accumulated liability.

g. Other Equipment

ALL OTHER EQUIPMENT is carried at cost and is depreciated over the estimated useful lives of the assets at annual rates varying from 10% to 30%.

h. Joint Venture

SUBSTANTIALLY ALL OIL AND natural gas production activities are conducted jointly with others. Accordingly, the accounts reflect the Fund's proportionate interest in these activities.

i. Cash Distributions

CASH DISTRIBUTIONS ARE CALCULATED on an accrual basis and are paid monthly to the Unitholders based upon funds available for distribution. *(See Note 6).*

j. Income Taxes

THE FUND IS AN INTER VIVOS trust for income tax purposes. As such, the Fund is taxable on any income which is not allocated to the Unitholders. The Fund intends to allocate all income to Unitholders. Should the Fund incur any income taxes, the funds available for distribution will be reduced accordingly. Provision for income taxes is recorded in EnerMark, and its subsidiaries at applicable statutory rates.

k. Deferred Reorganization Charges

DEFERRED REORGANIZATION CHARGES are related to the Arrangement. These charges are being amortized over a five year period.

l. Investments

INVESTMENTS ARE SHOWN ON THE balance sheet at the lower of cost or net realizable value.

m. Financial Instruments

FROM TIME TO TIME, THE FUND USES various financial instruments to manage risks associated with crude oil and natural gas price fluctuations. The instruments are not used for trading purposes. Proceeds and costs realized from holding the related contracts, all of which constitute effective hedges, are recognized in oil and gas revenues at the time that each transaction under a contract is settled.

n. Cash and Short Term Investments

THE FUND CONSIDERS ALL HIGHLY liquid investments with a remaining maturity of three months or less at the time of purchase to be cash equivalents. These cash equivalents consist primarily of funds on deposit under various terms. Cash equivalents and short-term investments are stated at cost which approximates market value.

2. Bank Debt

ENERMARK HAS BANKING ARRANGEMENTS for a revolving, extendible production credit facility (the "Facility") from a syndicate of Canadian chartered banks in the amount of $200,000,000 (1998 - $200,000,000, 1997 - $200,000,000). As at December 31, 1999, $68,685,000 was unutilized (1998 - $15,966,000, 1996 - $71,500,000). The Facility is reviewed annually. During the revolving period of the Facility, only interest payments are required. In the event the revolving period is not extended, an automatic term loan facility results requiring monthly interest payments with principal repayments made quarterly over a maximum period of five years. Interest charged on bank indebtedness is incurred under several pricing options, however, the maximum rate incurred will generally be the bank's prime rate. Substantially all of the assets of EnerMark are provided as security for the Facility in priority to all royalties or other securities of EnerMark held by the Fund.

The bank loan is the legal obligation of EnerMark. The Unitholders have no direct liability to EnerMark should the properties securing the debt generate insufficient revenues.

3. Related Party Transactions

PURSUANT TO AN AGREEMENT WITH EMR Resource Management Ltd. ("EMR"), EMR provides management, advisory and administration services to the Fund and EnerMark. As at December 31, 1999 $2,852,000 (1998 $1,462,000, 1997- $4,218,000) was payable to EMR pursuant to this agreement.

In addition to the fees of 2.2% (1998 - 2.2%, 1997 - 2.2%) of Canadian operating income which are reported on the Consolidated Statement of Net Income, EMR earned fees of $371,000 (1998 - $703,000, 1997 - $2,915,000) in relation to certain property acquisitions and divestitures of EnerMark. These amounts, which are based on 1.5% of the purchase price or 1.25% of the sales proceeds of oil and natural gas properties, are included in the cost of property, plant and equipment. In 1996, EMR also earned fees associated with the Arrangement in the amount of $5,000,000. These are included in deferred reorganization charges.

4. Fund Capital

a. Unitholders' Capital

Authorized: Unlimited number of EnerMark Income Fund Trust Units

	1999		1998		1997	
Issued:	Units	Amount	Units	Amount	Units	Amount
Balance, beginning of period	107,167,483	$ 538,004	109,933,012	$ 548,706	93,231,140	$ 436,433
Issued for cash:						
Pursuant to public offerings	16,533,602	47,952	-	-	13,000,000	87,185
Pursuant to Option Plans	165,651	419	-	-	635,756	4,106
Issued pursuant to Distribution Reinvestment Plan	1,919,987	6,319	1,762,006	8,190	817,278	5,413
Purchased for cancellation	-	-	(4,523,100)	(18,874)	-	-
Acquisition of Quest Oil & Gas, Inc. *(Note 7)*	-	-	-	-	1,190,660	8,070
Issued pursuant to sale of Units held by wholly-owned subsidiary	-	-	-	-	1,058,267	7,500
Redeemed	(533)	(1)	(4,435)	(18)	(89)	(1)
Fund capital	125,786,190	$ 592,693	107,167,483	$ 538,004	109,933,012	$ 548,706

PURSUANT TO AN OFFERING WHICH CLOSED August 26, 1999, the Fund issued 7,000,000 Units at a price of $3.80 per Unit. Costs of the issue were $1,530,000 and have been recorded as a reduction of Fund capital.

In February, 1999 the Fund issued 9,533,602 Units at a price of $2.45 per Unit pursuant to an Offer of Rights to subscribe for Trust Units which expired February 26, 1999. Costs of the issue were $755,000 and have been recorded as a reduction of Fund capital.

In January 1998, the Fund received regulatory approval to purchase for cancellation up to 5.4 million of its outstanding Trust Units. As at December 31, 1998 and to expiry of the plan on January 4, 1999, 4,523,100 Trust Units were purchased at an average cost of $4.17 per Unit, net of related fees.

In each of 1999 and 1998, EnerMark entered into joint venture agreements (the "1999 Arrangement", the "1998 Arrangement" and collectively, "the Arrangements") with separate corporations (the "Corporations") whose sole purpose is to hold oil and natural gas interests earned under each Arrangement. The terms of the Arrangements require the Corporations to commit funds to be spent in joint venture with EnerMark as described below. In addition, each Corporation has been granted the option to put its common shares to EnerMark at their fair value as determined by an independent evaluator on specified dates (the "Specified Dates"). EnerMark

may elect to pay for the shares by way of cash or through the issuance of Trust Units of the Fund. If Trust Units are issued they are to be valued at 95% of their average closing price for the 60 day periods preceding the Specified Dates, i.e.:

	Approximate Funding Commitment	Specified Date
1999 Arrangement	$2.7 million	March 1, 2002
1998 Arrangement	$2.8 million	February 1, 2001

Pursuant to a plan of arrangement which was completed on April 22, 1997, the Fund acquired all of the issued and outstanding shares and warrants of Quest Oil & Gas, Inc. *(Note 7)*. The total consideration paid included the issuance of 1,190,660 Units of the Fund recorded at a value of $6.778 per Unit.

The Fund issued 13,000,000 Units at a price of $7.10 per Unit pursuant to a short form prospectus which closed on August 9, 1997. Costs of the issue were $4,984,000 and have been recorded as a reduction of Fund capital.

Units are redeemable by Unitholders at any time, on demand, at 85% of the market price in effect from time to time.

Pursuant to a monthly Distribution Reinvestment and Unit Purchase Plan which became effective on March 1, 1997, Unitholders are entitled to reinvest cash distributions in additional Units of the Fund. Unitholders are also entitled to make optional cash payments to acquire additional Units. Units are issued at a discount of 5% below the weighted average market price on the Toronto Stock Exchange for the five trading days preceding a distribution payment date and without service charges or brokerage fees.

On October 29, 1997, a wholly-owned subsidiary of EnerMark disposed of its entire investment in the Fund consisting of 1,058,267 Units for total proceeds of $7,500,000, net of costs related to the sale.

b. Unit Options

ON AUGUST 22, 1996, A SPECIAL RESOLUTION was passed approving a Trust Unit Option Plan (the "Option Plan") for trustees, directors, officers, employees and consultants of the Fund or its affiliates and related parties involved in the management of the Fund. In addition to the Option Plan, certain previous employees of Mark who accepted positions with EnerMark were granted options for Trust Units, all of which expired on December, 31 1999. Combined activity for these options and options issued pursuant to the Option Plan is as follows:

	1999		1998		1997	
	Number of options (000s)	Weighted average exercise price	Number of options (000s)	Weighted average exercise price	Number of options (000s)	Weighted average exercise price
Unit Options outstanding beginning of year	4,705,428	$6.41	3,547,138	$6.58	2,846,967	$6.45
Granted	1,835,034	2.53	1,420,386	6.00	1,558,903	6.75
Exercised	(165,651)	2.53	-	-	(639,090)	6.46
Cancelled	(2,099,931)	6.39	(262,096)	6.45	(219,642)	6.56
Outstanding at end of year	4,274,880	4.90	4,705,428	6.41	3,547,138	6.58
Balance of Trust Units reserved but not issued	2,017,189		1,905,962		3,097,643	
Total Trust Units reserved as at the end of the period	6,292,069		6,611,390		6,644,781	

The following table summarizes information about outstanding Unit Options as at December 31, 1999

Outstanding at Dec. 31, 1999	Exercise Price	Expiring Dec. 31	Number exercisable at Dec. 31, 1999
1,631,873	$2.53	2001	543,957
1,316,676	$6.00	2002	877,783
955,908	$6.65	2000	955,908
166,130	$6.85	2000	166,130
204,293	$7.05	2000	204,293
4,274,880			2,748,071

5. Income Taxes

DURING 1999, THE FUND HAD taxable income of $20.0 million (1998 - $21.0 million and 1997 - $20.1 million) or 16.6 cents per Unit (1998 - 19.2 cents per Unit and 1997 - 20.3 cents per Unit) which was allocated to the Unitholders. Taxable income of the Fund is comprised of income on securities issued by EnerMark less deductions for Canadian oil and gas property expense ("COGPE"), which is claimed at a rate of 10 percent on a declining balance basis and the allowable portion of the cost of issuing new Trust Units during the period. Any losses which occur in the Fund must be retained in the Fund and may be carried forward and deducted from taxable income for a period of seven years. The amount of COGPE and issue costs remaining in the Fund are as follows:

	1999		1998		1997	
	Per Unit	Amount	Per Unit	Amount	Per Unit	Amount
COGPE	$0.77	96,993	$1.00	$107,770	$1.09	$119,744
Issue costs	0.04	4,800	0.05	5,132	0.06	7,145
Total	$0.81	101,793	$1.05	$112,902	$1.15	$126,889

The provision for income taxes in the consolidated statement of net income represents an effective tax rate different than the Canadian statutory tax rate. The differences are as follows:

	1999	1998	1997
Net income (loss) before taxes	$ 22,348	$ (2,774)	$ 22,719
Computed income tax expense (recovery) at the Canadian statutory rate of 44.62%	9,972	(1,238)	10,137
Increase (decrease) resulting from:			
Non-deductible crown royalties & other payments	11,279	9,466	11,368
Federal resource allowance	(9,935)	(7,214)	(10,171)
ARTC	(614)	(656)	(619)
Prior period ARTC recovery *(Note 8)*	-	(2,166)	-
Non-deductible depletion	1,176	1,133	2,113
Interest expense on EnerMark securities	(14,755)	(15,598)	(15,815)
Tax gain on dissolution of subsidiary	-	2,677	-
Reduction in tax liability due to a change relating to a prior year acquisition	(2,000)	-	-
Other	(80)	(21)	(17)
Deferred income taxes (recovery)	$ (4,957)	$(13,617)	$ (3,004)

As at December 31, 1999, property, plant and equipment included $38.8 million (1998 - $26.1 million, 1997- $43.7 million) of costs which have no tax base for income tax purposes.

6. Cash Available for Distribution

Reconciliation of cash available for distribution	1999	1998	1997
Funds flow from operations	$ 82,089	$ 63,929	$ 92,857
Cash withheld for debt reduction	(3,900)	-	-
Proceeds on sale of property, plant and equipment	-	6,130	-
Quest Oil & Gas, Inc. operating cash flow from effective date of acquisition to closing date	-	-	4,975
Deduct funds flow attributable to Units held by wholly-owned subsidiary	-	-	(667)
Cash available for distribution	$ 78,189	$ 70,059	$ 97,165
Cash available for distribution per Unit	$ 0.640	$ 0.640	$ 0.945

Cash available for distribution per Unit was paid to Unitholders as follows:

		1999		1998		1997	
For the month ended	Payment Date	Monthly Payment	Quarterly Total	Monthly Payment	Quarterly Total	Monthly Payment	Quarterly Total
Jan 31	Mar 20	$0.030		$0.075		$0.075	
Feb 28	Apr 20	0.030		0.075		0.075	
Mar 31	May 20	0.050	$0.110	0.075	$0.225	0.090	$0.240
Apr 30	Jun 20	0.030		0.055		0.075	
May 31	Jul 20	0.030		0.055		0.075	
Jun 30	Aug 20	0.090	$0.150	0.055	$0.165	0.090	$0.240
Jul 31	Sep 20	0.050		0.055		0.075	
Aug 31	Oct 20	0.050		0.040		0.075	
Sep 30	Nov 20	0.100	$0.200	0.045	$0.140	0.090	$0.240
Oct 31	Dec 20	0.060		0.040		0.075	
Nov 30	Jan 20/00	0.060		0.030		0.075	
Dec 31	Feb 20/00	0.060	$0.180	0.040	$0.110	0.075	$0.225
Cash available for distribution		$0.640	$0.640	$0.640	$0.640	$0.945	$0.945

7. Acquisition of Subsidiaries

a. Derrick Energy Corporation

PURSUANT TO A PLAN OF ARRANGEMENT which closed June 4, 1999, the Fund acquired all of the outstanding shares of Derrick Energy Corporation ("Derrick"), a public Alberta corporation engaged in the exploration and development of oil and natural gas reserves and immediately thereafter disposed of 80% of Derrick's petroleum and natural gas assets to other companies managed by The Enerplus Group. The total net consideration of $2,925,000 consisted of $26,888,000 in cash and $73,000 in costs associated with the arrangement less disposal proceeds of $24,036,000. The carrying value recorded in the accounts of Derrick exceeded the total consideration paid net of disposal proceeds by $2,575,000 and has been allocated as a decrease to EnerMark's property, plant and equipment. The net assets acquired and liabilities assumed are summarized as follows:

Property, plant and equipment	$	3,748
Working capital deficiency		(776)
Site restoration and abandonment		(47)
Net assets acquired	$	2,925

Derrick remained a wholly-owned subsidiary of EnerMark until January 1, 2000 when it was formally amalgamated with EnerMark and the amalgamated entity was continued under the name EnerMark Inc.

b. Quest Oil & Gas Inc.

ON APRIL 22, 1997, ENERMARK COMPLETED a plan of arrangement which resulted in the acquisition by EnerMark of all the issued and outstanding shares and warrants of Quest Oil & Gas, Inc. ("Quest") a public British Columbia corporation engaged primarily in the exploration for and development of oil and natural gas reserves. The total consideration of $124,885,000 consisted of 1,190,660 Units of the Fund, with a recorded value of $8,070,000, cash of $112,819,000 and costs associated with the acquisition in the amount of $3,996,000. The total consideration paid in excess of the carrying value recorded in the accounts of Quest has been allocated as an increase to EnerMark's property, plant and equipment in the amount of $42,554,000. The net assets acquired and liabilities assumed are summarized as follows:

Property, plant and equipment	$	148,782
Working capital deficiency		(4,181)
Long-term debt assumed		(17,808)
Site restoration and abandonment		(1,908)
Net assets acquired	$	124,885

Quest remained a wholly-owned subsidiary of EnerMark until May 1, 1997 when it was formally amalgamated with EnerMark and the amalgamated entity was continued under the name EnerMark Inc.

8. Recovery of Alberta Royalty Tax Credit ("ARTC")

THE RECOVERY OF ARTC WAS THE RESULT of a successful appeal to recover ARTC assessed against Mark prior to its reorganization into EnerMark in April, 1996. The amount included on the 1998 Consolidated Statement of Net Income includes $2,900,000 of related interest.

9. Financial Instruments

THE FUND'S FINANCIAL INSTRUMENTS that are included in the balance sheet are comprised of accounts receivable, current liabilities and long-term debt. The fair values of these instruments, that are included in the balance sheet, approximate their carrying amount due to their short term to maturity and the variable interest rates applied to long-term debt. Virtually all of the Fund's accounts receivable are with customers in the oil and natural gas industry and are subject to normal industry credit risks.

The Fund uses various types of financial instruments to manage the risk related to fluctuating commodity prices. The fair values of these financial instruments, presented as "Market Value" in the table below, are based on an approximation of the amounts that would have been paid or received by counter parties to settle these instruments prior to maturity. As at December 31, 1999, the following contract positions were outstanding:

Natural Gas

Instrument	Volumes gigajoules/day	$Cdn/gigajoule at AECO	Term: Expiry	Term: Months Remaining	Market Value
Swap	2,000	$3.29	Oct. 31, 2000	10	$ 270
Call option	5,000	$2.50	Oct. 31, 2001	22	1,405
Combined put/swap	800				
put option component		$2.70	Mar. 31, 2001	15	37
swap option component	-	$2.75	Oct. 31, 2004	43	(147)
	7,800				$ 1,565

Crude oil

Instrument	Volumes bbls/day	Price $/bbl	Term: Expiry	Term: Months Remaining	Market Value
Swap	33	$21.57 US -WTI	Sept. 30, 2000	9	$ (15)
Combined put/call	1,750	Floor: $26.50 Cdn - WTI Equivalent Ceiling: $30.60 Cdn - WTI Equivalent	Dec. 31, 2000	12	(1,705)
	1,783				$ (1,720)

The Fund is exposed to credit risk associated with the counter parties to the financial instruments. The Fund mitigates this risk by assessing the financial stabilty and capacity of counter parties prior to entering into financial instrument contracts with such counter parties.

In addition to the above instruments that were in effect on December 31, 1999, the Fund has subsequently entered into a combined commodity price put option contract comprising 4,000 bbls/d of crude oil at $33.10 Cdn, WTI equivalent and 20,000 gigajoules/day of natural gas at $2.65 Cdn/gigajoule at AECO. This contract is designed to preserve a notional base revenue stream for the combined commodities for the period April 1, 2000 to December 31, 2000.

10. Subsequent Events

a. Acquisition of Western Star Exploration Ltd.

PURSUANT TO AN OFFER TO PURCHASE, which closed January 7, 2000 and a subsequent compulsory acquisition order, the Fund acquired 100% of the outstanding common shares of Western Star Exploration Ltd. ("Western Star"), a public Alberta corporation engaged in exploration and development activities in the province of Alberta. Under the terms of the offer, each Western Star shareholder could elect to receive either $1.80 in cash or 0.48 of a Trust Unit and 0.75 of a warrant, or a combination thereof, for each Western Star share tendered. Each whole warrant is exercisable for one Trust Unit at a price of $4.00 per Trust Unit until December 31, 2000. As of the date hereof, 1% of the Western Star shareholders elected to receive Trust Units and warrants resulting in the issuance of 72,593 Trust Units and 113,426 warrants. The balance have received cash. The total consideration paid by the Fund is approximately $21.5 million before the assumption of Western Star's net debt in the approximate amount of $5.9 million and costs associated with the acquisition of $0.6 million.

b. Acquisition of Hanna Garden Natural Gas Property

THE FUND PURCHASED A LONG-LIFE, natural gas property effective December 31, 1999 for consideration of $13 million in cash and 6,050,000 Trust Units of the Fund valued at approximately $3.50 per Unit. The purchase agreement closed on February 28, 2000. The net cost to the Fund is expected to be $34.7 million inclusive of related costs and expenses.

c. Acquisition of Pursuit Resources Corp.

ON MARCH 9, 2000, THE FUND MADE a take-over bid ("the Offer") to acquire all of the issued and outstanding common shares of Pursuit Resources Corp. ("Pursuit") Under the terms of the Offer, shareholders of Pursuit may elect to receive 0.8 of an EnerMark Trust Unit or $3.00 in cash (to a maximum cash consideration of $15 million) for each Pursuit common share tendered to the Offer. The total purchase price will be approximately $114.5 million including the assumption of approximately $35 million outstanding bank loans but before costs associated with the Offer and fees associated with the acquisition of approximately $2.5 million.

detailed
Statistical Review

($ thousands, except per Unit amounts)	1999	1998	1997	1996[1]
Financial				
Gross oil and gas sales	$ 169,541	$ 134,102	$ 173,919	$ 132,423
Cash available for distribution	$ 78,189	$ 70,059	$ 97,165	$ 65,131
Per Unit	$ 0.640	$ 0.640	$ 0.945	$ 0.810
Net income	$ 25,754	$ 8,881	$ 23,855	$ 19,838
Per Unit	$ 0.22	$ 0.08	$ 0.24	$ 0.27
Capital expenditures, net of dispositions	$ 12,136	$ 56,516	$ 19,998	$ 76,715
Total assets	$ 576,901	$ 617,881	$ 670,203	$ 551,544
Bank debt, net of working capital	$ 134,519	$ 185,507	$ 102,925	$ 38,357
Net debt/funds flow ratio (1996 annualized)	1.6x	2.9x	1.1x	0.4x
Market price per Unit				
High	$ 4.31	$ 6.55	$ 7.65	$ 7.90
Low	$ 2.26	$ 2.68	$ 5.60	$ 6.20
Close	$ 3.59	$ 3.17	$ 6.40	$ 7.55
Volume traded (000 Units)	40,154	37,367	62,039	71,751
Cash available for distribution				
Funds flow from operations	$ 82,089	$ 63,929	$ 92,857	$ 65,988
Cash withheld for debt reduction	$ (3,900)	-	-	-
Proceeds on sale of property, plant & equipment	-	6,130	-	-
Quest Oil & Gas Inc. operating cash flow from effective date of acquisition to closing date	-	-	4,975	-
Deduct funds flow attributable to Units held by wholly-owned subsidiary	-	-	(667)	(857)
Cash available for distribution	$ 78,189	$ 70,059	$ 97,165	$ 65,131
Cash available for distribution per Unit	$ 0.640	$ 0.640	$ 0.945	$ 0.810

[1] for the period from inception April 3, 1996 to December 31, 1996

detailed Statistical Review

	1999	1998	1997	1996[1]
Oil and gas economics				
($ per BOE except percentage data)				
Gross royalty rate	19.8%	19.6%	18.9%	20.5%
Alberta Royalty Tax Credit	(0.8)	(1.1)	(0.8)	(1.0)
Net royalty rate	19.0%	18.5%	18.1%	19.5%
Weighted average selling price	$ 22.58	$ 16.56	$ 21.14	$ 23.48
Net royalty expense[2]	(4.28)	(3.07)	(3.82)	(4.57)
Operating expense	(4.96)	(4.99)	(4.85)	(4.60)
Cash netback	13.34	8.50	12.47	14.31
General and administrative expense	(0.76)	(0.69)	(0.55)	(0.94)
Management fee	(0.29)	(0.19)	(0.28)	(0.35)
Profit margin	$ 12.29	$ 7.62	$ 11.64	$ 13.02
Operating				
Production				
Crude oil and NGLs (Mbbl)	4,890	5,230	5,419	3,747
Per day (bbl)	13,396	14,328	14,846	13,624
Average selling price (per bbl)	$ 22.39	$ 15.16	$ 22.42	$ 27.26
Natural gas (MMcf)	26,175	28,674	28,066	19,567
Per day (Mcf)	71,713	78,558	76,894	71,154
Average selling price (per Mcf)	$ 2.31	$ 1.92	$ 1.87	$ 1.53
MBOE	7,507	8,097	8,226	5,703
Per day (BOE)	20,567	22,184	22,535	20,739
Established reserves (proven and 50% of probable)				
Crude oil and NGLs (Mbbl)	65,265[3]	67,759	63,092	53,721
Natural gas (MMcf)	509,554[3]	384,745	396,083	326,175
MBOE	116,221[3]	106,233	102,700	86,338
Established reserve life index[4] (years)				
Crude oil and NGLs	14.3[3]	14.0	12.2	11.0
Natural gas	17.4[3]	14.9	13.9	13.6
BOE	15.5[3]	14.3	12.8	11.9

[1] for the period from inception April 3, 1996 to December 31, 1996
[2] excludes 1998 recovery of prior period ARTC
[3] includes acquisitions of Hanna Garden, effective December 31, 1999 and Western Star, effective January 7, 2000 for a combined total of 14,660 MBOE
[4] the established reserve life index is based on year end established reserves divided by total following year volumes contained in the proven, producing reserve study

Distribution Reinvestment and Unit Purchase Plan

ENERMARK INCOME FUND HAS DEVELOPED a convenient method of reinvesting cash distributions or investing additional funds into new Trust Units. Any residents of Canada who hold Trust Units may participate in the Plan.

Features of the Plan Include:

- New Units are purchased monthly at a 5% discount with reinvested distributions;
- Optional cash payments of the greater of the distribution received on Units held or up to $5,000 per month may be made to purchase new units at the same 5% discount regardless of whether monthly distributions are being reinvested;
- No service charges or brokerage fees are incurred by Unitholders and all administrative costs of the Plan are borne by the Fund;
- Participants will receive regular statements regarding their purchases.

If your units are held for you by your broker, investment dealer or other financial intermediary, you must direct that company to complete the necessary authorization forms.

You can make an optional cash payment when enrolling in the Plan by enclosing a cheque or money order payable to "The CIBC Mellon Trust Company" with the completed authorization form.

For more information and/or enrolment forms, please contact the Investor Relations at 1-800-319-6462, in Calgary at (403) 298-2200, by fax at (403) 298-2211 or by email: investorrelations@enerplus.com.

EnerMark Internet Site - www.enerplus.com

ENERMARK INCOME FUND HAS A COMPREHENSIVE website to provide investors with an immediate source of all public information.

Annual and Quarterly Reports

Tax Information

Recent Presentations

Historical Distribution Tables

Adjusted Cost Base Calculator

Fact Sheets

News Releases

15 Minute Delayed Stock Quote

Distribution Reinvestment and Unit Purchase Plan

corporate Information

Officers

Marcel J. Tremblay
President and Chief Executive Officer

Dennis R. Gieck
Executive Vice President and
Chief Operating Officer

Kelly I. Drader
Senior Vice President

Karen A. Genoway
Senior Vice President

Eric P. Tremblay
Senior Vice President, Corporate Development

Gordon J. Kerr
Vice President, Finance and
Chief Financial Officer

Patrick J. Cairns
Vice President, Evaluations

Daryl Cook
Vice President, Operations

Heather Culbert
Vice President, Administration and M.I.S.

Dorothy J. Else
Vice President, Land

Raymond J. Giroux
Vice President, Special Projects

Darrell Shaw
Vice President, Exploitation

Wayne T. Foch
Treasurer

Christina S. Meeuwsen
Corporate Secretary

Richard D. Parsons
Controller

Head Office

Western Canadian Place
1900, 700 - 9th Avenue S.W.
Calgary, Alberta T2P 3V4
Telephone: (403) 298-2200
or: 1-800-319-6462
Fax: (403) 298-2211

Related and Associated Entities

EMR Resource Management Ltd.

EnerMark Inc.

Legal Counsel

Blake Cassels & Graydon
Calgary, Alberta and Toronto, Ontario

Auditors

PricewaterhouseCoopers LLP
Calgary, Alberta

Bankers

Canadian Imperial Bank of Canada
Calgary, Alberta
The Bank of Nova Scotia
Calgary, Alberta
The Bank of Montreal
Calgary, Alberta

Transfer Agent

The CIBC Mellon Trust Company
Calgary, Alberta
1-800-387-0825; email:
inquiries@cibcmellon.com

Stock Exchange Listing

The Toronto Stock Exchange

Trading Symbol

EIF.UN

Website

www.enerplus.com

Annual Information Form

A copy of the Annual Information Form is available upon request by writing to Investor Relations, EnerMark Income Fund, Suite 1900, 700 - 9th Avenue S.W., Calgary, Alberta T2P 3V4 or by calling 1-800-319-6462.

Publié également en français: veuillez vous addresser à EnerMark, Directeur, Expansion de la Société, à 1-800-319-6462

Annual General and Special Meeting

The Annual General and Special Meeting of the Unitholders of EnerMark Income Fund will be held in Conference Room A, Plus 30 Level of Western Canadian Place, 700 - 9th Avenue, S.W., in Calgary, Alberta, commencing at 2:30 p.m. on May 24, 2000. Unitholders are encouraged to attend and those unable to do so should complete the Form of Proxy and forward it at their earliest convenience.

Abbreviations

AECO "C"/NIT	=	Alberta Energy Company interconnect with the Nova System
ARTC	=	Alberta Royalty Tax Credit
bbl	=	barrel
bbl/d	=	barrel(s) per day
Bcf	=	billion cubic feet
BOE(s)	=	barrel of oil equivalent (10 Mcf gas = 1 bbl crude oil)
BOE/d	=	barrel of oil equivalent per day
Mbbl(s)	=	thousand barrels
MBOE	=	thousand barrels of oil equivalent
Mcf	=	thousand cubic feet
Mcf/d	=	thousand cubic feet per day
MMbbl(s)	=	million barrels
MMBOE	=	million barrels of oil equivalent
MMbtu	=	million British Thermal units
MMcf	=	million cubic feet
MMcf/d	=	million cubic feet per day
NGLs	=	natural gas liquids
RLI	=	reserve life index
TSE	=	The Toronto Stock Exchange
WTI	=	West Texas Intermediate at Cushing, OK.

EnerMark Income Fund
Western Canadian Place
Suite 1900, 700 - 9th Avenue SW
Calgary Alberta
T2P 3V4
Telephone: 403 298 2200
1 800 319 6462
Fax: 403 298 2211
www.enerplus.com
Email: Investorrelations@enerplus.com